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CONTROL OF SULFUR OXIDE POLLUTION FROM POWER PLANTS

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Summary and Conclusions

Sulfur oxides are among the most hazardous of air pollutants. Studies have related human health effects of varying severities to sulfur dioxide (SO_2) concentrations. Sulfur dioxide has also been shown to be deleterious to plant life, to decrease visibility under certain conditions, and to lead to accelerated corrosion of many common materials, The estimate of the cost to society due to air pollution is many billions of dollars annually, with SO_2 and particulate matter the major contributors to this cost. About 55% of the SO_2 emitted in this country is from power plants; this percentage is projected at 75% in the year 2000, assuming no control. It is, therefore, of critical importance to this country's air pollution program, to limit the emissions of SO_2 from power plants.

The Clean Air Amendments of 1970 activated a schedule that will result in decreasing SO_2 emissions from power plants for both new and existing facilities. The Standards of Performance for New Stationary Sources limits power plant emissions to prescribed quantities for both solid and liquid fossil fuels. However, utilities still have at least 2 years to make a decision on a control system since power plants affected by this Standard will not be complete until 1975, and control systems require about 2 years from go-ahead to installation. In order to meet primary ambient SO_2 standards, it will be necessary to limit the emissions of existing power plants by no later than early 1975,

Due to the substantial projected growth of coal and fuel oil utilization by the growing power industry, even relatively stringent control strategies will only control the exponential growth in SO_2 over the next 2 decades; they will not drastically decrease emissions over present values, A nomograph has been prepared which estimates the sulfur content in a fossil fuel required to meet various control standards.

About 62% of the total electricity generated by fossil fuels is produced by burning coal. There does not appear to be sufficient low-sulfur Eastern steam coal to meet the anticipated requirements. Although there is

enough low-sulfur Rocky Mountain coal production potential to supply the total country, substantial costs are associated with transporting this coal to Eastern power plants and huge investments in production facilities would be required. Although physical desulfurization of Eastern steam coal is considered a well-developed process, it can only contribute a small fraction of the low-sulfur cost required in the Eastern power plants.

It appears that low-sulfur oil can be made available for all oil-burning power plants, although at substantially higher costs, The techniques which must be used to increase production include:

1) increased imports of North African low-sulfur oils,
2) increased U. S. production,
3) increased blending, and
4) increased desulfurization of the high-sulfur content South American/Middle East production,

Among the more than 50 desulfurization control processes which have been proposed, these are considered to be sufficiently well characterized to potentially make a significant contribution to SO_2 control within the next 5 years:

1) wet lime/limestone scrubbing process,
2) wet magnesium oxide scrubbing, and
3) catalytic-oxidation.

At least 20 full-size desulfurization control processes for power plants are in the design, construction or operation phase in the United States at this time. Nineteen of these use one of the three processes listed above; 16 of these are wet lime/limestone systems,

Wet lime/limestone systems are more fully characterized than other control systems. They utilize scrubbing of flue gases with lime or limestone slurries forming a sludge waste product, They have relatively low capital and operating costs with potentially high removal efficiencies. However, problems have been identified; they are: chemical scaling, erosion/corrosion, solids waste disposal, and plume heat requirements,

There has been a considerable amount of bench model, pilot plant and prototype experimental activity in the limestone wet scrubbing area in recent years. Various scrubber types have been shown to operate reliably with acceptable removal efficiencies under the following conditions: high liquid-to-gas ratios, high solids content in slurry, and long delay times in a delay tank following the scrubber. Full-size facilities with wet limestone process operating experience are discussed; they include the Howden-ICI Fullham unit, the A. B. Bahco facility, and the three Combustion Engineering boiler injection/wet scrubbing facilities. Important information will be generated soon on the EPA prototype facility at Shawnee and the Will County full-scale limestone scrubbing unit.

The magnesium oxide (MgO) scrubbing process is described, It is similar to wet lime/limestone processes, except that the magnesium sulfite and sulfate reaction products are regenerated, producing a concentrated stream of SO_2 for H_2SO_4 production and regenerated MgO for reuse. Removal efficiency is estimated at 80-90%. The Boston-Edison 125 Mw Chemico MgO scrubbing and regeneration facilities are described; the facility will start up within several weeks. Areas of potential concern which will be evaluated during the 12-month test period include: potential scaling and plugging problems, attainment of design removal efficiency (90%), potential erosion/corrosion problems, regeneration effectiveness, and overall system reliability.

Monsanto has developed a modified version of the well-known contact H_2SO_4 process for use in removing SO_2 from power plant flue gas. Two systems are described: the first is for new plants (reheat system); the second, for existing plants (integrated system). It is essential to remove at least 99.6% of the dust prior to the introduction of the flue gas through the fixed vanadium pentoxide catalyst bed to avoid plugging. There is also a requirement to maintain the flue gas at about 850° F. in order to sustain the oxidation reaction. The integrated process was tested on a 15 Mw facility at Metropolitan Edison's Portland Station; results indicated the process can remove 85-90% of the SO_2.

The process is being scaled-up on a 100 Mw boiler at the Wood River Power Plant of the Illinois Power Company. Start-up is planned for June 1972; a 1 year test program is planned.

The dry limestone injection process is briefly described. In light of the inherently low removal efficiencies and potential boiler plugging problems, it does not appear this process will play an important role in controlling SO_2 power plant emissions.

There is some indication that before the end of 1972 some of the uncertainties associated with control process selection will be dissipated. This is based on the start-up and testing of several important facilities during 1972. They include: the EPA wet lime/limestone prototype facility, the full-scale MgO process at Boston Edison, and the catalytic-oxidation system at Illinois Power.

The various control processes are compared with each other in terms of removal efficiency, capital and operating costs, and with low-sulfur fuel in terms of operating costs. Although generalizations on process costs are considered hazardous, of the effective control systems, it appears that wet lime/limestone processes have the lowest capital cost, followed by MgO; the catalytic oxidation process is the most expensive. Wet lime/limestone systems appear to have the lowest operating cost if sale of H_2SO_4 is not assumed for the MgO and catalytic-oxidation systems. When credit is given for sale, operating costs for wet lime/limestone and MgO appear quite similar and significantly lower than those of the catalytic oxidation process. However, for byproduct recovery systems, operating costs are significantly affected by the assumed market value of the product. Value of the products is a function of location and time, and can only be estimated. It appears that the three control processes discussed offer an economic incentive for utilization over low-sulfur fuel for many power plants, although power plant location and the fossil fuel type utilized strongly affect any comparison.

I. The Importance of Sulfur Oxide Control

Sulfur oxides are among the most dangerous air pollutants to human health and are clearly the most harmful to vegetation, buildings and materials. Because their source is chiefly the electric power industry, their potential increase is tied to that burgeoning industry which almost doubles its output every 10 years. Analyses of numerous epidemiological studies clearly indicate an association between air pollution, as measured by SO_2 concentration, and health effects of varying severities. Studies have shown that mortality and morbidity can be correlated to SO_2 ambient levels. Such a correlation has been particularly evident during air pollution episodes in New York City, Donora, Pa., and London, England. Studies have indicated adverse health effects when 24-hour average levels of SO_2 exceeded 0.11 ppm for 3-4 days. Sulfur dioxide is considered a gas of high toxicity; for example, adverse health effects have been noted for carbon monoxide, a gas with a reputation for high toxicity, or levels only above about 9 ppm. Evidence has been cited which indicates that there is a synergistic effect between SO_2 and ambient particulate matter; i.e., the health effects of a combination of these pollutants are more pronounced than the sum of their individual effects. This fact has an obvious implication to power plant pollution control, since power plants are also major emitters of particulate matter.

In addition to its deleterious effect on man directly, SO_2 is toxic to plant life; typical ambient levels in polluted locations can cause acute or chronic leaf injury to a variety of trees, shrubs, agricultural crops, and many other plant species.

Sulfur dioxide pollution also causes many millions of dollars a year in material replacement costs due to corrosion. Studies have shown ambient concentrations of SO_2 to sharply increase corrosion of steels, electrical equipment, limestone, marble and many other common materials.

Also, low concentrations of SO_2 markedly decrease visibility. For example an SO_2 concentration of 0.10 ppm and a relative humidity of 50%, visibility can be reduced to about 5 miles.

Although it is difficult to estimate the costs to society of SO_2 pollution, many billions of dollars a year are estimated for air pollution in general, of which SO_2 and particulate matter are the most important pollutants. These costs result from decreased lives of steel structures, electrical equipment, commercial laundering and cleaning of fabrics and automobiles; and damage to agricultural crops and livestock,

Table 1 quantitatively lists the estimated SO_2 pollution in the United States without control. From this table, it is evident that power plants are responsible for most of the country's SO_2 pollution problem. In 1970, about 55% of the SO_2 emissions were from power plants; this percentage is estimated at 75% in the year 2000 assuming no pollution control.

Due to the dangerous and deleterious nature of SO_2, and the power plant's high emission rate, it is not an overstatement to say that control of SO_2 emissions from power plants is one of the most important goals of this country's air pollution program.

II. The Clean Air Amendments of 1970

The Clean Air Amendments of 1970 activated a schedule that will result in decreasing SO_2 emissions from power plants for both new and existing facilities. The recently promulgated Standards of Performance for New Stationary Sources limits the emission of SO_2 for power plants to 0.80 lb SO_2 per million Btu heat input when liquid fossil fuels are burned, and 1.2 lb SO_2 per million Btu when solid fuels are burned, These standards apply to power plants for which construction or modification commenced after August 17, 1971.

Figure 1 presents a design and construction time chart that roughly indicates the time that a utility has in selecting a control system for a new power plant subject to the performance standard. It should be noted that there is about a 3-year time period in which a decision can be made on selection of a control system. This results from the fact that power plants greater than about 200 Mw require about 5 years from engineering start to commercial operation, while the corresponding time period for a control system, (e.g., wet scrubber) is about 2 years.

The Clean Air Amendments indirectly provide for control of existing power plants, since Implementation Plans are required of each state which include a control strategy for assuring maintenance of the promulgated ambient air quality standards for sulfur oxides, particulate matter, carbon monoxide, photochemical oxidants, hydrocarbons, and nitrogen dioxide. The following national primary ambient air quality standards have been set for sulfur dioxide:

80 $\mu g/m^3$	(.03 ppm) annual arithmetic mean
356 $\mu g/m^3$	(.14 ppm) max, 24-hour conc not to be exceeded more than once a year

In order to meet the above SO_2 standards, it will be necessary to limit the emissions of existing power plants in many of the 237 air quality regions in many of the states since, as mentioned earlier, they are the major SO_2 emitters. The Clean Air Amendments call for attainment of this primary standard as soon as possible, but no later than three years from date of approval of such plans. Approvals are scheduled to be made early this year, so standards must be met by early 1975.

Figure 2 estimates the effect that various SO_2 control strategies will have on power plant emissions. It is evident from the figure, that uncontrolled power plant emissions (Case A) will lead to an exponential growth in SO_2 emissions over the next 2 decades. Also apparent is that, even with control for both new and existing plants (cases C and D), SO_2 levels will not show any substantial decrease compared to present levels.

It is important to note that control strategies presently contemplated for new and existing power plants will control only the upward spiral in SO_2 emissions; they will not dramatically decrease total emissions from present values.

III. Ways of Controlling Emissions

Due to the expected dependence of the United States on the burning of coal and oil over the next 3 decades in order to produce the required electrical power, it is imperative that SO_2 emissions must be controlled to avoid the exponential increase emissions projected (Figure 2, case A).

Figure 3 shows the projected electric generation by source from 1965-1990; Figure 4 shows the projected annual fossil fuel requirements for electrical utility generation. In order to provide for the required growth in total thermal energy from fossil fuels, coal will become increasingly important over the next 3 decades, with growth of oil utilization also indicated. Gas utilization is projected as leveling off over the next 3 decades. The implication of this is that coal and oil, the two most undesirable fuels from an emission viewpoint, will require sharply increased utilization over the next 3 decades to meet the projected growth rate of fossil fuel produced electrical power. It is this predicted trend that leads to a prediction of spiralling sulfur oxide emission rates, unless substantial controls are implemented.

There are two basic approaches which can be used to control power plant sulfur oxide emissions--use of low-sulfur fuel or installation of a flue gas desulfurization control system. As subsequent discussions will indicate, use of low-sulfur fuel is limited by both availability and economic considerations. For this reason it appears both approaches will be extensively utilized throughout the country; the decision of which way to go for a particular power plant will be highly dependent on a particular power plant's geographical location and its fossil fuel type.

A. Low-Sulfur Fuels

"Low-Sulfur Fuel" is a qualitative term which can be meaningfully defined in terms of a relevant emission standard. Figure 5 is a nomograph that can be used to show the quantity of sulfur required for three coals and residual oil, based on the new stationary source performance standards. The nomograph can also be used to estimate allowable flue gas SO_2 concentrations based on excess air used during combustion. In order to meet the new performance standard: bituminous coal must have a sulfur content less than about 0.80%; subbituminous, less than 0.53%; and lignite, below 0.42%. Sulfur content in typical residual oils must be below about 0.73%.

Until the last several years, selection of a fossil fuel for a particular power plant has been based almost totally on economic considerations; i.e., the lowest cost readily available fuel in terms of $/Btu was selected without regard to sulfur content. For this reason, historically, distinct trends in fossil fuel types were readily apparent for the various regions of the country, based on fuel availability and cost considerations. For example, power plants in the East Coast Region (New England, Middle Atlantic, and South Atlantic) have traditionally burned relatively high sulfur Appalachian coal. However, recently, due to sulfur emission restructions and rising coal costs, power plants in New England and those immediately adjacent to deep-water ports have changed to imported low-sulfur residual oils. Due to the scarcity of natural gas in the East, there is a general decline in the use of natural gas, with much of the new natural gas demand intended for dual-fueled plants; i.e., plants which can operate on an alternate fossil fuel in the event of supply shortages.

In the Interior Region, coal (with a substantial quantity of natural gas) has been used primarily as power plant fuel. The coal used has been low-cost, high-sulfur coal in the East North-Central and East

South-Central states; however, a trend has been noted--an increasing use of both low-sulfur Rocky Mountain coal (in response to local emission regulations) and residual oil (with a corresponding decrease in the use of natural gas).

Natural gas represents 50% of the fossil fuel used by West Coast Region power plants. Also, a trend has been noted toward the use of residual oil in this area. This is the case despite the availability of low-sulfur Rocky Mountain coal, primarily due to stringent air pollution control regulations in California would discourage the use of coal. It should be noted that hydroelectric power is a major source in the West Coast Region, thereby reducing fossil fuel requirements substantially.

Based on a survey by the Federal Power Commission, the distribution of sulfur content of fuel burned by utilities in 1969 is available. Figures 6 and 7 present a distribution of sulfur contents for coal and oil, respectively. This survey indicates that coal burned in the U. S. by power plants ranged in sulfur content from 0.4 to 6% by weight; the weighted average was 2.58%. Similarly, the sulfur content of oil used by electric utilities ranged from about 0.3% to 3%, with the weighted average at 1.66%. It should be noted that this data indicates bimodal distribution curves for both coal and oil, with one peak at below 1% sulfur content. This most likely reflects an early response by several utilities to local air pollution control regulations requiring the use of fuels with less than 1% sulfur. An even more pronounced shift in similar distribution curves is expected for subsequent years as utilities attempt to meet local and federal emission regulations.

A comparison of the sulfur content in fuels burned by new power plants required by the standards of performance for new stationary sources, with the fuels actually utilized in 1969, indicates that a major change in low-sulfur fuel utilization and/or extensive use of desulfurization processes is mandatory for new power plants. Similar constraints will be placed on many existing power plants based on state control strategies to meet the ambient standards.

In 1970, about 40% of all electrical power was produced by burning coal. This corresponds to about 62% of the total electricity produced by burning fossil fuels; the remainder was produced by hydroelectric and nuclear power generation.

Table 2 shows estimated identifiable mineable reserves and estimated annual commercial production for low-sulfur coal and all coal by coal region. This table shows that the great majority of the Appalachian and Interior coals, both produced and reserves, have sulfur contents in excess of 1.2 lb $SO_2/10^6$ Btu (0.6 lb $S/10^6$ Btu). However, Rocky Mountain coals have naturally low-sulfur contents and roughly 23% of the reserves and 79% of the 1970 coal production in this area has a sulfur content less than 1.2 lb $SO_2/10^6$ Btu. Table 3 indicates that known recoverable reserves of commercially available (non-captive to the metallurgical industry) low-sulfur coal in the Eastern United States appear adequate to supply only a portion of the required Eastern annual demand growth rate. However, there appears to be sufficient Western production potential to meet the demands of the total United States by 1975, although substantial transportation costs are associated with supplying Rocky Mountain coal to Eastern power plants. The variability in delivered cost is a strong function of the transportation distance from the coal mine to the power plant. For example, the cost of Rocky Mountain coal delivered in Chicago is about 50% higher than Eastern Steam Coal; whereas, such coal in Washington, D. C., would be about 130% higher in cost, based on an assumed unit train transportation cost of \$0.034 per 10^6 Btu (\$0.75 per ton) per 100 miles. It should be noted that vastly increased production from Rocky Mountain mines, about 20 million tons annual growth rate, would be required to supply the coal needed by the coal burning Eastern power plants. Such increased production appears technically feasible with a 3-year period, since much of the coal is near the surface and amenable to strip mining. A major impact of such a production growth will be the need for an extensive railroad system needed to transport the coal.

Such an increase in mining production requires very large capital investments that can only be made if long term (15-20 year) contracts can be assured or if the cost of fuel is increased to permit amortizing investment at a much faster rate. Since it appears likely that flue gas desulfurization processes will be available leading to an effective fuel cost increase of less than 50%, the substantial investments needed for drastically increased Rocky Mountain production may not be made based on such uncertain prospects for capital recovery.

Another possibility for supplying Eastern power plants with low-sulfur coal is physical desulfurization or "deep cleaning" of coal. This process involves a coal crushing operation to release the pyritic sulfur followed by a physical separation of the pyrite from the coal. This practice is considered well-developed; design and construction of a coal cleaning plant using existing technology is estimated at 3 years. However, the potential increase in low-sulfur control production possible through physical desulfurization is only a small fraction of the low-sulfur coal required for Eastern power plants. Coal desulfurization is estimated to increase Eastern steam coal costs by about 10%.

Oil as a power plant fuel is used largely by utilities that can be supplied by water transportation. The large increase in delivered fuel cost that would result from overland transportation of fuel oil will likely be the limiting factor governing the expansion of fuel oil use into the utility market. Although oil is the energy source for only about 9% of the fossil fuel utilized by power plants in the United States, due to the need for substantially increased production rates (Figure 4) in light of the projected demand, it is desirable that low-sulfur oil production capabilities be correspondingly increased.

Four techniques can be utilized to increase the availability of low-sulfur oils: 1) increased imports of North African natural low-sulfur oils (about 0.3% S), 2) increased United States production of low-sulfur residual oil, 3) increased blending of high- and low-sulfur oils, and 4) increased desulfurization of the high-sulfur content South American/ Middle East production. Chemical desulfurization can be accomplished by

one of several relatively new processes, including residium hydrodesulfurization and vacuum gas-oil (VGO) hydrodesulfurization. At the present time the cost increment associated with desulfurization of South American oil is about 25-30%; as compared to about a 12% cost increment for importation of North African low-sulfur oil. It appears that a combination of the above techniques could make low-sulfur oil available for all oil-burning power plants for the next two to three decades, although such fuel will undoubtedly lead to fuel cost increases for many users.

Natural gas is the most desirable fossil fuel in terms of freedom from sulfur oxide, particulate, and nitrogen oxide emissions. In general, the sulfur content of the delivered gas is negligible with correspondingly negligible sulfur oxide emissions. However, projections have indicated a very rapid decline in the rate of growth of gas usage for power generation; Figure 4 shows this trend. The primary reason for this projection is the scarcity of natural gas; only about 4% of the total known fossil fuel potential thermal inventory in the United States is natural gas. Coal represents 80% of the total reserves.

To supply the present demands of natural gas, the U. S. depends primarily on domestic production supplemented by importation, primarily from Canada. Presently, Canadian importation represents about 3% of total U. S. production. However, future requirement projections indicate a substantial increase in importation of natural gas, both in the gaseous phase from Canada and as liquified natural gas from South America, North Africa, and the Middle East. The estimated East Coast delivered price of liquified natural gas is estimated at from 80% to 180% higher than the present domestic "as burned" average price of U. S. produced gas.

In light of the larger coal reserves, compared to petroleum or natural gas fossil fuels, there is a large incentive in developing processes which convert coal into more ecologically and potentially

more economically attractive gaseous fuels. The goal of such processes, which are under intensive development, is to produce high - Btu (at least 900 Btu per feet^3) gas which could be transported economically through new or existing pipeline systems from points of manufacture to centers of consumption. Although such processes appear to have important long term potential, based on the available technology, they do not appear to have a significant effect on availability of gaseous fuels for power plant utilization until at least 1980.

In summary, there appears to be sufficient production potential for supplying Rocky Mountain coal for all the power plants requiring 1.2 lb $SO_2/10^6$ Btu coal by 1975. Also, there appears to be a number of techniques to supply the projected growth rate of low-sulfur oil for the next two to three decades. Although projections of low-sulfur fuel costs are difficult due to the transient state of supply/demand to the power plant, there is no question that low-sulfur fuels delivered to the power plant will be substantially higher than present fuel costs. For many power plants there will be economic incentive to utilize a control process instead of changing to a low-sulfur fuel.

B. Sulfur Dioxide Control Processes

In light of the substantial costs associated with low sulfur fossil fuel in many parts of the country, it will become necessary for many power plants to install control processes. There are more than 50 SO_2 control processes, and their major variations. Of these, only four are considered developed sufficiently to enable reasonable estimation of expected performance and economics. For the purposes of this discussion, three of these four processes are considered sufficiently developed, with acceptable SO_2 removal efficiencies, to potentially make a significant contribution to the control of new or modified power plants within the next five years. The dry limestone injection process, although well characterized, has a removal efficiency too low for most power plant requirements. These processes will be discussed in this paper.

The three processes which are considered sufficiently developed to potentially desulfurize flue gas on a full-scale commercial basis, within the next five years are:

- Wet lime/limestone scrubbing
- Magnesium oxide scrubbing
- Catalytic oxidation

At least 20 full-size desulfurization control processes for power plants are in the design, construction or operational phase in the United States at the present time. Table 4 lists these facilities by control process type. The contracts for these facilities are estimated to be $200 million, with $140 million of this total to be spent for retrofit of equipment on existing power plants. Of the 20 facilities listed, 19 use one of the three processes considered first generation; 16 of these use one of the several variations of the wet lime/limestone process. The sodium-base scrubbing process to be utilized at Nevada Power Company's Reid

Gardner Station involves scrubbing with sodium carbonate and disposition of solid wastes in an evaporation pond.

Among the firms that have contracts for full-scale flue gas desulfurization systems are: Babcock & Wilcox, Chemico, Combustion Engineering, Combustion Equipment Association, Monsanto, Peabody Engineering, Research Cottrell, and Zurn. Generally, the control systems have been designed for 80 to 90% SO_2 removal, with many of them accomplishing high-efficiency particulate removal as well.

The following discussion describes and presents the status of: wet lime/limestone systems, magnesium oxide scrubbing, catalytic oxidation and dry limestone injection control processes.

1. Wet Lime/Limestone Systems

As Table 4 indicates, the great majority of full-size power plant desulfurization systems in both the planning and operational phase involve scrubbing with limestone or lime. The primary reasons for this are that these processes: are more fully characterized than other first generation systems; have relatively low capital and operating costs; and have high potential removal efficiencies. However, along with characterization comes familiarity with such process problems as chemical scaling, erosion/corrosion, solid waste disposal, and plume heating requirements.

Several methods have been developed for the use of limestone and lime in a wet scrubbing process. The major variations are schematically illustrated in Figure 8. In Method 1, Scrubber Addition of Limestone, the flue gas is contacted with a slurry containing finely ground limestone. The limestone is added directly to a portion of scrubber effluent for recycle. Part of the scrubber discharge goes to a settler (or a pond) where the solid product is removed. Settler overflow can either be recycled as shown or

discharged to waste. The next method, Scrubber Addition of Lime, is similar to Method 1 except that the limestone is first calcined externally before addition to the scrubber circuit. In the final method, Boiler Injection, the limestone is calcined in the boiler (as in the dry injection system) and carried to the scrubber in the flue gas. Figure 9 shows the Commonwealth Edison Company's Will County Station - Unit No. 1. This unit utilized limestone introduced in the scrubber circuit. This figure was included to show the major equipment items needed for a typical full-size wet limestone installation.

In addition to being classified according to whether lime or limestone is the reactant, the above processes are further classified as cyclic or non-cyclic. Such a classification refers to whether the aqueous liquor loop is totally recycled (cyclic operation) or totally purged (non-cyclic operation) to a stream or reservoir, giving rise to possible water pollution problems. In light of potential water pollution problems, the great majority of the 16 full-size installations operate in a total or near-total recycle mode. The ultimate disposition of the sludge solids is generally in a large pond at the power plant site; when land is not economically available, the sludge is transported to the most economical surface disposition area available.

The chemical reactions occurring in the above systems, although seemingly simple, are neither well understood nor universally agreed upon. The following chemical reactions have been postulated for flue gas scrubbing and appear to be the most plausible on the basis of experimental data available.

$$SO_2(g) \rightleftharpoons SO_2(aq)$$

$$SO_2(aq) + H_2O \rightleftharpoons H_2SO_3 \rightleftharpoons H^+ + HSO_3^-$$

$$HSO_3^- \rightleftharpoons H^+ + SO_3^=$$

$$CaCO_3(s) \rightleftharpoons CaCO_3(aq)$$

$$CaCO_3(aq) \rightleftharpoons Ca^{++} + CO_3^=$$

$$Ca^{++} + SO_3^= + 0.5\ H_2O \rightleftharpoons CaSO_3 \cdot 0.5\ H_2O(s)$$

$$CO_3^= + H^+ \rightleftharpoons HCO_3^-$$

$$H^+ + HCO_3^- \rightleftharpoons H_2CO_3(aq)$$

The overall reaction is:

$$CaCO_3(s) + SO_2(g) + 0.5\ H_2O \longrightarrow CaSO_3 \cdot 0.5\ H_2O(s) + CO_2(g)$$

There has been a considerable amount of bench model, pilot plant, and prototype experimental activity in the limestone wet scrubbing area. An extensive effort has been expended on a variety of scrubber types, by a large number of organizations, over the last 30 years. Over the last several years, pilot plant effort has been particularly active and substantial advances have been made in wet limestone technology. Scrubber types which have received the most attention in recent years have been the: venturi, Turbulent Contact Absorber (TCA), Hydrofilter (flooded marble bed), spray tower, and packed tower. Generally, pilot plant results have indicated that under carefully selected operating conditions all of these scrubbers, with the probable exception of the packed tower due to its inherent plugging

tendencies, can be operated with relatively high SO_2 and particulate removal efficiencies with acceptable reliability. Pilot plant testing has indicated that, with relatively high liquid-to-gas ratios, high solids content in the scrubber slurry, long residence times in a delay tank following the scrubber, and a proper choice of scrubber type, the desirable combination of good removal efficiencies without excessive down-time can be achieved.

For example, the results of both the Ontario-Hydro and the Tennessee Valley Authority (TVA) pilot plant programs indicate that good performance and reliability have been achieved on a pilot-size scale. Ontario-Hydro was able to achieve SO_2 removal efficiencies of 70-80% in its spray tower, under reasonable operating conditions, with good reliability; scaling or plugging was not a major problem. TVA has been able to achieve high removal efficiencies for three scrubber systems: a venturi-rod (modified venturi)/ spray tower, a three-stage TCA, and multi-grid tower. For the venturi-rod/ spray unit, SO_2 removal efficiencies of 77% over a 354-hour test were achieved with only 20 hours of down-time. Particulate removal efficiency was measured at from 98.9% to 99.3%. For the TCA unit, SO_2 removal efficiencies of up to 92% and a particulate removal efficiency of 98.3% have been measured during a 172-hour test. Although the unit showed no scaling or plugging tendencies, erosion of the balls, grids, and nozzles was excessive; design modifications are being considered to minimize this problem. For the multi-grid scrubber, a 270-hour test yielded an SO_2 removal efficiency of 85% with no scaling or plugging. Particulate removal was about 98.9%. TVA reports that demister operation has been troublesome, however, with some solids buildup ($CaSO_4 \cdot 2H_2O$).

At the present time, four full-size scrubber facilities have been constructed and have generated varying amount of operating data. An additional unit, the London Power Fullham Plant, was constructed and tested in the late 1930's. This unit is considered the first commercial application of wet

limestone scrubbing of power plant flue gas. It was operated 1936-39 yielding very high SO_2 and particulate removals, without substantial scaling or plugging problems. In fact, many of the techniques used to control scaling and plugging on this unit have been utilized successfully in recent years. However, the facility was afflicted with corrosion and erosion problems which led to considerable down-time and high maintenance costs. The unit was taken off the line during the early stages of World War II, when the stack plumes were considered markers for enemy airmen. Before shutdown, a plant modification decreased the removal efficiency to 90%, but gave some promise of being able to remain in service for much longer periods without repair. This unit is considered to have indicated the feasibility of wet limestone scrubbing for power plants on a commercial basis.

The AB Bahco unit, which utilizes a two-stage inspirating scrubber with lime as the reactant, is considered an operational full-size scrubber facility despite its small size (the equivalent of 25 Mwe for the three units) since it is a commercial unit servicing oil-fired boilers in a hospital in Stockholm, Sweden. This system is considered the most successful of the operational wet limestone scrubber facilities presently in operation. This system has been operated at 95-98% removal efficiencies for extended periods of time (6 months) without interruption due to scaling or other problems. Recently, Cottrell announced that it has licensed the Bahco process for use in the United States. At the present time, they will accept orders for scrubber facilities up to 40 MW in size.

In the United States, Combustion Engineering, Inc. has constructed and operated three full-size scrubber facilities: two in 1968 at existing coal-fired power plants (the 125 MW Kansas Power & Light Lawrence Station No. 4 and the 140 MW Union Electric Meramec No. 2), and the third, on a new plant (the 420 MW Kansas Power & Light Lawrence Station No. 5). These units all employ boiler injection of limestone followed by wet scrubbing in

single-stage flooded-bed scrubbers (Hydro-filters). These plants were expected to remove about 85% of the SO_2 from flue gas generated using about 3.5% sulfur coal. The two smaller units have experienced major operational difficulties, including scaling, plugging, and corrosion. However, the 125 MW unit was tested in June 1971 for 100 hours with only minor operational problems (nozzle pluggage), during which approximately 60% SO_2 removal was obtained. Currently, the scrubbing system is being modified to solve the nozzle pluggage problem and to increase the SO_2 removal through increased liquid flow rates to the scrubber and increased bed overflow recycle to the effluent hold tank (for better limestone utilization). The object of these revisions is to reliably demonstrate 70-75% SO_2 removal. This program will be supported by EPA-funded testing on the 11,000 CFM Combustion Engineering pilot unit in Windsor, Connecticut.

The Union Electric unit was also tested in May-June 1971 with SO_2 removals similar to the 125 MW unit. However, mechanical equipment problems, mostly unrelated to limitations in the process design, limited continuous operation to about 80 hours. Boiler pluggage was also a major problem with this unit. Although modifications to this unit could make it comparable in reliability to the 125 MW unit, none are currently planned.

The 420 MW unit was tested for 100 hours in September 1971 during which maldistribution of gas flow to the six scrubbers was noted. Gas flow control modifications have since been made. The unit was started up again using coal on November 28, 1971. Currently, low stoichiometric addition of limestone (50-60%) has been employed to avoid scaling. Low pH bed overflow recycle, to mix with the high pH scrubber effluent, is being considered to improve limestone utilization. Currently, information on SO_2 removal is not available for this unit.

Early this month, the 175 MW Commonwealth Edison Will County Station-Unit No. 1 (Figure 9) started up. Data should be available soon to indicate the performance and reliability of this wet limestone system. This system is the first full-scale installation in the United States that uses limestone introduced into the scrubber circuit. This system is representative of a trend in recent years away from the boiler injection mode due to the possibility of boiler pluggage and the tendency of serious scaling problems, primarily due to the greater reactivity associated with lime slurries, compared to limestone slurries.

It should be noted that construction of the most versatile wet limestone test facility, the EPA prototype facility at Shawnee, is nearing completion. When this facility is put in to operation late this month, it should add considerably to the body of the knowledge of wet limestone scrubbers. This program is a cooperative effort with TVA and Bechtel Corporation, EPA's major partners in this effort. Most of the major scrubber types using both limestone (added to the scrubber circuit or injected in the boiler) and lime (added to the scrubber circuit) will be tested in a comprehensive program using a sophisticated data acquisition and handling system with extensive process instrumentation.

2. Magnesium Oxide Scrubbing.

In many respects, the magnesium oxide (MgO) scrubbing process is similar to lime (CaO) scrubbing. The principal difference is that the spent magnesium sulfite and sulfate salts are regenerated producing a concentrated stream of 10-15% SO_2 and regenerated MgO for reuse in the scrubber loop. Since the reactant is recycled, it must be protected from contamination by fly ash. It is, therefore, necessary that the process be applied on an oil-fired boiler or that the fly ash be sufficiently removed from the flue gas prior to passing it into the MgO desulfurization process.

This process was first developed by the Grillo Company of Hamborn, Germany. In 1968, Grillo scaled up the small pilot plant which it had operated for about one year to a 15,000 cfm scrubbing facility installed on an oil-fired boiler of Union Kraft at Wesseling, Germany. The reactant used was principally MgO with about 6% manganese dioxide. Spent reactant from the scrubber was shipped from Wesseling to Hamborn where it was calcined in a vertical kiln with a carbon reducing agent to assist in the regeneration of $MgSO_4$. During the development program, Grillo adopted the centralized reprocessing concept which suggests that the superior economics associated with a large regeneration facility will offset the cost of transporting spent reactant to a centralized site and the regenerated reactant back to the utility. This concept is similar to and probably stems from the custom smelting practices of certain nonferreous smelting operators, of which Grillo is one.

In the United States, the Chemico Corporation is following a nearly identical approach to that of Grillo. EPA and Boston Edison are cost-sharing the development of a MgO scrubbing and regeneration process on a 125 MW oil-fired unit at Boston Edison's Mystic Station. The flow sheet for this process, which is currently under construction by Chemico, is schematically shown in Figure 10. This facility is scheduled to start up within several weeks, and should provide important information in many technical areas. Areas of potential concern with the process, which will be evaluated during the 12-month test program, include: potential scaling and plugging problems, attainment of 90% design efficiency, potential erosion/corrosion problems, effectiveness of the regeneration step, and overall system reliability. The results of these tests will be particularly important since there is only a limited amount of information on this process based on prior pilot-plant testing by Chemico and Babcock & Wilcox. Also, this demonstration represents the first time that the individual steps of scrubbing, centrifuging, and calcining have been operated on an integrated basis for the Chemico system.

In the EPA-Boston Edison demonstration, only the equipment for absorption, centrifuging, and drying will be located at the power plant. Spent reactant will be shipped to the Essex Chemical Plant at Rumford, Rhode Island, where it will be calcined to produce SO_2 for making about 50 tons per day of 98% sulfuric acid. The SO_2 produced during regeneration will provide feed for this plant's total acid output.

A second full-scale magnesium oxide SO_2 removal facility is planned for Potomac Electric and Power's Dickerson No. 3 unit. Approximately 100 MW of the 195 MW of this unit will be processed. Since this facility burns coal (3% sulfur, 8% ash), the scrubbing facility consists of two venturis in series: the first removes fly ash particulates; the second absorbs the SO_2. Present plans are to use the aforementioned calcination facility located at the Essex Chemical Plant. This facility is scheduled to start up early in 1974.

For both the Boston Edison and Potomac units, the particulate-free SO_2 -containing flue gas from the power plant enters the venturi absorber where it contacts a dense spray of the slurry absorbing liquor. The absorbing liquor consists primarily of magnesium sulfite ($MgSO_3$), magnesium sulfate ($MgSO_4$), and magnesium oxide (MgO). Fresh MgO slurry is added as a makeup to the venturi absorber. The clean flue gas passes through a separator-demister section and exhausts to the stack. A bleed from the absorber goes to a centrifuge for separation of the solids from the mother liquor. The mother liquor is returned to the absorber system. The wet cake from the centrifuge, containing water of hydration and surface moisture, is dried in a direct-fired rotary kiln. Hot drier exhaust gases pass to the stack where they provide reheat for the flue gas from the absorber.

The anhydrous crystals leaving the drier, after addition of carbon, are next reacted in a direct-fired calciner to regenerate MgO and release

sulfur oxide. The high operating temperature (about 1800-2000°F) is needed to regenerate the relatively small quantities of $MgSO_4 \cdot 7H_2O$ that form from oxidation of $MgSO_3 \cdot 6H_2O$. The regenerated MgO produced is mixed with makeup water and reused in the absorber system. The calciner off-gass containing 15-16% SO_2 is sent to a conventional sulfuric acid plant for further processing. Table 5 lists the chemical reactions which have been postulated for the major steps of the process.

3. Catalytic Oxidation (Cat-Ox)

Monsanto has developed a modified version of the well-known contact H_2SO_4 process for removing SO_2 from power plant flue gas. Basically, the process consists of passing the flue gas through a fixed catalyst bed where SO_2, in the presence of O_2, is converted to SO_3. The SO_3 is then absorbed in recirculated H_2SO_4 in an absorption tower.

Besides being designed for the dilute SO_2 concentrations found in flue gas, the Cat-Ox process differs from the conventional contact process in two principal respects: first, the flue gas entering the process must either already be at a high enough temperature, about 850°F, for the conversion of SO_2 to SO_3, or heat must be supplied. The heat of reaction alone, because of the low SO_2 concentration, is insufficient to maintain the required temperature. Second, SO_2-containing gas (flue gas) entering the system is not dried prior to entering the converter.

For power plant applications, Monsanto has proposed two versions of the process: first, the "integrated system" for use on new plants and second, the "reheat system" for use on existing plants. These variations are shown in Figures 11 and 12.

In the "integrated system", schematically depicted in Figure 11, hot flue gas at about 850°F is taken directly from the boiler and passed through an efficient dust collection system (mechanical collectors plus an electrostatic precipitator) to remove at least 99.6% of the particulates. The gas then flows through a converter where, in contact with a vanadium pentoxide catalyst at about 850°F, oxidation of the SO_2 occurs. Flue gas from the converter is next cooled in an economizer followed by an air heater. By maintaining the operating temperature of these units above the dew point of H_2SO_4, corrosion problems are avoided. Sulfuric acid in the flue gas is then condensed in a packed-bed absorber by direct contact with acid recycled from an external cooler, producing an 80% acid product. Acid mist and any remaining dust in the flue gas is then removed in a highly efficient, fiber-type mist eliminator and passed out the stack.

The "reheat system" shown in Figure 12 is similar to the "integrated system". However, the temperature of the entering gas is typically about 325°F in this system, compared to 850°F in the "integrated system." Therefore, the electrostatic precipitator need not be designed for such an extreme temperature service. High efficiency dust removal is still required, however. The low temperature of the entering gas also necessitates raising the gas to reaction temperature before it enters the converter. This is done by using the converter exhaust gases to preheat the incoming gas. To supply the additional heat required, hot gas from the combustion of oil or gas is added directly. With these exceptions, the two systems are essentially alike.

Monsanto tested the "integrated process" on a 15 Mw scale at Metropolitan Edison's Portland Station. These tests, which covered a 2 year period from 1967 to 1969, indicated the capability of the process to remove 85-90% of the sulfur dioxide. In addition, the information required for scale-up of the process was obtained.

The principal technical problems with the Cat-Ox process for power plant applications are associated with fly ash removal. Dust must be removed with high efficiency from the incoming flue gas. Otherwise, it will plug the converter catalyst and fiber-bed mist eliminator and contaminate the acid product. Plugging of the catalyst bed required a 2-3 day shutdown of the converter for cleaning and results in a catalyst loss of about 2.5%. Monsanto estimates that catalyst cleaning will be required at about 2-3 month intervals. The 99.6% collection efficiency required of the precipitators is near the upper limit of presently available equipment. The technical success of the process will depend to a large extent on how well this critical requirement can be met.

This process is now being scaledup on a 100 Mw boiler at Wood River Power Plant of the Illinois Power Company. The $6.7 million cost of the demonstration will be shared by EPA and Illinois Power. Start-up, planned for June 1972, will be followed by a 1 year test program.

A primary advantage of the Cat-Ox process is that no raw materials, other than the flue gas and catalyst makeup, are required. The low-concentration H_2SO_4 produced may be a serious disadvantage, depending on the marketing situation.

4. Dry Limestone Injection

The dry limestone injection process is considered a fairly well characterized control process with only limited potential, due primarily to inherently low removal efficiencies. The process involves the injection of pulverized limestone directly into the power plant boiler where it is calcined to lime and subsequently reacts at high temperature with SO_2 and excess oxygen in the boiler to form calsium sulfate. The calcium sulfate is then removed as a solid with the fly ash by mechanical collectors and electrostatic precipitators.

Although the overall dry limestone process is quite simple, the phenomena occurring in the reaction zone of the boiler are very complex. The limestone injected into the boiler must calcine and react with the sulfur oxides present within a time span of 2 seconds or less. If the limestone is injected too close to the flame, the lime produced will be dead-burned and become unreactive. If the limestone is injected higher or farther from the flame, the residence time in the zone of the boiler favoring reaction with sulfur oxides will be seriously reduced.

Because of the difficulty of translating results from small-scale studies to full-scale boiler, a number of prototype and full-scale investigations of the process have been carried out. The most extensive studies have been done by investigators in Germany, Japan, Czechoslovakia, and the United States.

Results from test programs on three full-scale operating boilers have also been reported. STEAG (Steinkohlen-Elektrizitat) in Germany obtained 20-30% removal in test on a 20 Mw boiler with 1.0-1.3 times stoichiometric amounts of limestone burning 1.5% sulfur coal. The

University of Stuttgart achieved 50% removal on a small, coal-fired boiler with 2.8 times the stoichiometric amount of hydrated lime injected at 1832°F. They obtained 77% removal under comparable conditions using oil as the fuel. In plant-scale tests on an oil-fired boiler in Japan, CRIEPI obtained removals of 40-50% with 2-3 times the stoichiometric quantity of limestone.

Although recognized and investigated for many years, the process had not been characterized adequately to enable its confident full-scale utilization. For this reason, the most comprehensive full-scale test program on the process was initiated under a joint EPA-TVA project performed at the Shawnee Station near Paducah, Kentucky. The program has recently been completed. The process was installed on a 140 Mw boiler burning an average 2.7% sulfur, pulverized coal. The system contains equipment for injecting limestone at rates up to about 4 times the stoichiometric amount. In addition, the system permitted the location, angle, and velocity of limestone injection to be varied for evaluating the effects of these parameters on performance.

The goal of the Shawnee test program was to establish the conditions for optimum system performance and obtain comprehensive design and cost information. Results from the comprehensive test effort have indicated that:

1) the location, angle, and velocity of injection have little effect on limestone distribution. Gas turbulence as determined by boiler operating conditions is the major factor controlling distribution.

2) injection of the limestone at locations corresponding to low temperature/low residence time gives improved SO_2 removals compared with high temperature/high residence time locations.

3) SO_2 removal efficiencies are quite low; for most limestones with the boiler operating at or near full load only about 11% per unit of stoichiometry can be expected with 95% confidence. This removal can increase by a factor up to two if a reactive limestone, such as marl, is available, and/or if the boiler is operated near 50% load conditions.

4) use of this process can lead to severe operating problems. For example, during testing at Shawnee, severe boiler reheater pluggage occurred after only 6 days of continuous testing. Union Electric has experienced similar pluggage problems in their boiler during testing of their boiler-injection/wet-limestonesystem installed at their Meramec No. 2 Station. It It should be noted, however, that such problems have not been severe at asimilar system installed at Kansas Power & Light's Lawrence Station No. 4 or at Detroit Edison's St. Clair No. 6 Unit. Differences associated with boiler pluggage potential are attributed to specific boiler design features of which tube spacing and temperature regime are considered major parameters. Shawnee tests have also indicated operational problems with the particulate water-slurry sluice disposal system, due to hydroveyor deposition and plugging difficulties.

5) degraded electrostatic precipitator performance resulting from higher dust loading of higher resistivity particulate has been reported. Reductions in efficiency ranged from 10% average to about 25%, were measured at Detroit Edison and Shawnee. Test results from the latest precipitator test program at Shawnee are not yet available.

In light of the inherently low removal efficiencies, and the potential for major reliability problems, it does not appear that the dry limestone injection process will play an important role in controlling SO_2 emissions from power plants. While the process may find some use for particular situations, its application is expected to be limited.

C. A Comparison of Control Techniques

The important question that power utilities with existing or planned fossil-fuel facilities must answer in the near future is whether to install a control system or use a low-sulfur fuel; and, if a control system is to be installed, a selection must be made among the wet limestone systems from one of the serveral firms offering variations of this process, the Chemico MgO process, the Monsanto Catalytic-Oxidation, or another less characterized control system. Unfortunately, there are no simple answers to these questions at the present time. Low-sulfur fuel costs are in a somewhat transient state and the availability of certain fuels in certain locations is uncertain, since new emission regulations are placing new supply/demand constraints on the fossil-fuel marketplace with worldwide ramifications. Also, there is insufficient information to firmly conclude which is the most attractive of the control systems being commercially offered. Add to these uncertainties the specific requirements of a given power plant and the problem becomes quite complex. However, there is some indication that toward the end of this year some of the uncertainties may be clarified, particularly with regard to control system selection. The following important events are scheduled this year.

1) The EPA wet limestone prototype facility will start up late this month. Test results should indicate relative attractiveness of many of the various wet limestone systems commercially offered, and present important information on reliability and economics of operation.

2) At least eight full-scale wet limestone systems will start up and operate in 1972. These include the following: Commonwealth Edison's Will County Station No. 1; Kansas City Power & Light's Hawthorne Stations No. 3 and No. 4, and their La Cygne Station; Detroit Edison's River Rouge Station No. 1; Louisville Gas and Electric's Paddy's Run Station No. 6; and the City of Key West's Stock Island facility. EPA is hopeful that with utility cooperation, this operating experience will be made available to other interested utilities.

3) The full-scale magnesium oxide scrubbing and regeneration facilities will start up (March 1972) and generate operating information.

4) The catalytic oxidation process will be demonstrated on a full-scale basis during 1972; startup is scheduled during June 1972.

Table 6 compares SO_2 control techniques based on information presently available. When considering the estimated removal efficiencies, it may be useful to note that a removal efficiency of about 75% is needed to meet the new source performance standards with 3% sulfur bituminous coal. As mentioned earlier, based on the many facilities which will startup and generate test data during this year, this comparison can only be considered preliminary. It is particularly hazardous to generalize on control costs: costs must be calculated for a specific application and usually cannot be readily extrapolated to predict costs for other applications. This is the case, since there are many factors which can exert a major influence on costs. For example, for control processes, the following factors are among those that influence cost: size of power plant, new versus retrofit unit, amounts of sulfur and ash in fuel, pollution control requirements, price of reactant, solid waste disposal constraints and scrubber type. However, ranges of capital and operating costs for four control processes as well as a range of operating costs associated with lower sulfur fuel were included in Table 6 to allow a preliminary comparison.

In general, the capital and operating costs for the dry limestone injection process are substantially lower than those for other control systems. However, application is limited by relatively low removal efficiencies and potential operating problems. Wet limestone systems have somewhat lower capital costs than either the MgO or the catalytic-oxidation process; they also have lower operating costs if credit is not considered for H_2SO_4 sale. When credit for H_2SO_4 sale is considered, operating costs

for wet limestone and MgO systems are quite close; costs for the catalytic-oxidation system appear substantially higher. It should be noted, however, that operating costs for processes producing a sulfur product are quite sensitive to the market value of that product, which is a strong function of time and location. Also, from an environmental viewpoint, it is desirable that disposable reaction products not be produced from a control process; this is the situation for the MgO and catalytic-oxidation systems but not for the wet lime/limestone systems with their sludge product.

A cost of 2.0 to 6.0 mills/Kw·hr is estimated for low-sulfur fuel. Such cost numbers are strongly dependent on fuel type and plant location. However, preliminarily, it appears that control system operating costs, which include capital amortization, are generally lower than low-sulfur fuel costs. Therefore, it appears that there is economic incentive for the installation of control processes for old and new power plants in many parts of the country.

TABLE 1. ESTIMATED SULFUR DIOXIDE POLLUTION IN U.S. WITHOUT ABATEMENT

	Annual emission of sulfur dioxide (millions of tons)			
	1970	1980	1990	2000
Power plant operation (coal and oil)	20.0	41.1	62.0	94.5
Other combustion of coal	4.8	4.0	3.1	1.6
Combustion of petroleum products (excluding power plant oil)	3.4	3.9	4.3	5.1
Smelting of metallic ores	4.0	5.3	7.1	9.6
Petroleum refinery operation	2.4	4.0	6.5	10.5
Miscellaneous sources	2.0	2.6	3.4	4.5
Total	36.6	60.9	86.4	125.8

Table 2.

ESTIMATED COMMERCIAL BITUMINOUS AND SUBBITUMINOUS STEAM COAL RESERVES AND PRODUCTION

REGION	# SO_2 /10^6 BTU	CUMULATIVE MINEABLE RESERVES 10^6 TONS	CUMULATIVE MINEABLE RESERVES 10^{12} BTU	ESTIMATED CUMULATIVE ANNUAL COMMERCIAL PRODUCTION (1970) 10^6 TONS	ESTIMATED CUMULATIVE ANNUAL COMMERCIAL PRODUCTION (1970) 10^{12} BTU
APPALACHIAN	< 1.2	1,650 (3,000)	43,000 (78,000)	44	1150
	All Coal	9,770 (25,000)	254,000 (650,000)	175	4540
INTERIOR	< 1.2	53	1,270	0.5	11
	All Coal	136,580	3,278,000	166	3980
ROCKY MOUNTAIN	< 1.2	18,000	380,000	15	315
	All Coal	78,000	1,640,000	19	400

Table 3.

MAXIMUM ANNUAL STEAM COAL PRODUCTION GROWTH BASED ON RESERVES

	SULFUR CONTENT #S/10^6 BTU	MAXIMUM ANNUAL PRODUCTION GROWTH 10^6 TONS	10^6 BTU	% OF AVERAGE ANNUAL EASTERN DEMAND GROWTH	% OF AVERAGE ANNUAL U.S. DEMAND GROWTH
EASTERN U.S. (1975 DEMAND GROWTH-625 x 10^{12} Btu)	<0.6	5.3	135	24%	19%
	All Coal	350	9100	1590%	1255%
				% OF AVERAGE ANNUAL WESTERN DEMAND GROWTH	
WESTERN U.S. (1975 DEMAND GROWTH-125 x 10^{12} Btu)	<0.6	44	925	640%	130%
	All Coal	210	4400	2930%	610%

TABLE 4

PLANNED AND OPERATING FUEL SIZE FLUE GAS DESULFURIZATION FACILITIES

Utility company/plant	Megawatts	Startup	Fuel
LIMESTONE SCRUBBING			
1. Union Electric Co. (St. Louis)/ Meramec No. 2	140	September 1968	3.0% S coal
2. Union Electric Co. (St. Louis)/ Meramec No. 1	125	Spring 1973	3.0% S coal
3. Kansas Power & Light/ Lawrence Station No. 4	125	December 1968	3.5% S coal
4. Kansas Power & Light/ Lawrence Station O. 5	430	November 1971	3.5% S coal
5. Kansas City Power & Light/ Hawthorne Station No. 3	130	Mid 1972	3.5% S coal
6. Kansas City Power & Light/ Hawthorne Station No. 4	140	Mid 1972	3.5% S coal
7. Kansas City Power & Light/ La Cygne Station	820	Late 1972	5.2% S coal
8. Detroit Edison Co./ St. Clair Station No. 3	180	November 1972	2.5-4.5% S coal
9. Detroit Edison Co./ River Rouge Station No. 1	290	December 1972	3-4% S coal
10. Commonwealth Edison (Chicago area)/ Will County Station No. 1	175	February 1972	3.5% S coal
11. Northern States Power Co. (Minnesota) Sherburne County Station No. 1 & 2	Total 1360	May 1976 First Unit	0.8% S coal
12. Arizona Public Service Co./ Cholla Station	115	January 1973	0.4%-1% S coal
13. Tennessee Valley Authority/ Widow's Creek Station No. 8	550	April 1975	3.7% S coal
14. Duquesne Light Co. (Pittsburgh)/ Philips Station	100	February 1973	2.3% S coal
15. Louisville Gas & Electric Co./ Paddy's Run Station No. 6	70	Mid-Late 1972	3.0% S coal
16. City of Key West/Stock Island*	37	June 1972	2.75% S fuel oil
SODIUM-BASE SCRUBBING			
17. Nevada Power Co./ Reid Gardner Station	250	Mid 1973	1.0% S coal
MAGNESIUM OXIDE SCRUBBING			
18. Boston Edison/Mystic Station No. 6*	150	Mar-1972	2.5% S fuel oil
19. Potomac Electric & Power (Maryland)/ Dickerson No. 3*	195	Early 1974	3.0% S coal
CATALYTIC OXIDATION			
20. Illinois Power/Wood River*	100	June 1972	3.5% S coal

*Partial funding by the Environmental Protection Agency

TABLE 5

CHEMISTRY OF MgO SLURRY PROCESS

ABSORPTION

MAIN REACTION

$$MgO + SO_2 + 6\,H_2O \rightarrow Mg\,SO_3 \cdot 6\,H_2O$$

SIDE REACTIONS

$$Mg\,SO_3 + SO_2 + H_2O \rightarrow Mg\,(HSO_3)_2$$

$$Mg\,(HSO_3)_2 + MgO \rightarrow 2\,Mg\,SO_3 + H_2O$$

$$MgO + SO_3 + 7H_2O \rightarrow Mg\,SO_4 \cdot 7\,H_2O$$

$$MgSO_3 + 1/2\,O_2 + 7\,H_2O \rightarrow MgSO_4 \cdot 7\,H_2O$$

DRYING

$$MgSO_3 \cdot 6\,H_2O \overset{\Delta}{\rightleftarrows} MgSO_3 + 6\,H_2O$$

$$MgSO_4 \cdot 7\,H_2O \overset{\Delta}{\rightleftarrows} MgSO_4 + 7\,H_2O$$

$$H_2O\,(\ell) \overset{\Delta}{\rightleftarrows} H_2O\,(g)$$

REGENERATION

$$MgSO_3 \overset{\Delta}{\rightleftarrows} MgO + SO_2$$

$$MgSO_4 + 1/2\,C \overset{\Delta}{\rightleftarrows} MgO + SO_2 + 1/2\,CO_2$$

TABLE 8. SUMMARY OF SO_2 CONTROL PROCESS SYSTEMS

PROCESSOR METHOD	REACTANT INPUT REQUIREMENTS	THROW-AWAY OR RECOVERY	INVESTMENT COSTS $/kw (for coal boilers)	OPERATING COSTS mills/kwhr		SO_2 REMOVAL EFFICIENCY	COMMENTS
				NO CREDIT FOR S RECOVERY	CREDIT FOR S RECOVERY		
LOW SULFUR FUEL	N.A.	N.A.	0	2.0 - 6.0	N.A.	N.A.	COSTS DEPENDENT ON LOCATION AND FUEL TYPE.
DRY LIMESTONE INJECTION	LIMESTONE 200%. STOICH.	THROW AWAY	12 - 14 (200 MW. NEW)	0.6 - 0.8	N.A.	22-45%.	COSTS DEPENDENT ON SOLIDS REMOVAL VARIABLES REMOVAL DEPENDENT ON LIMESTONE TYPE AND BOILER LOAD LIMITED IN APPLICABILITY.
WET LIME LIMESTONE SCRUBBING	LIME. 100-1200%. STOCK LIMESTONE 120-150%. STOICH.	THROW AWAY	27 45 (200 - 1000 MW. NEW OR RETRO)	1.1 - 2.2	N.A.	80-90%.	COSTS DEPENDENT ON SOLIDS REMOVAL CONSIDERATIONS NEW OR RETROFIT SCRUBBER TYPE LIME OR LIMESTONE SIZE OF UNIT ETC. CONSIDERED MOST ADVANCED TECHNOLOGY SEVERAL COMMERCIAL UNITS IN OPERATION TESTING ON EPA PROTOTYPE INITIATED
MAGNESIUM OXIDE SCRUBBING	MgO ALKALI WATER FUEL FOR REGENERATION & DRYING	RECOVERY OF CONC. H_2SO_4	33 - 58 (200 - 1000 MW. NEW OR RETRO)	1.5 - 3.0	0.9 - 2.6	80-90%.	COSTS DEPENDENT ON SAME FACTORS FOR WET LIMESTONE BOSTON ELECTRIC UNIT TO START-UP IN MARCH 1972 H_2SO_4 ASSUMED MARKETED AT 18 $/ton. ON-SITE ACID PRODUCTION.
MONSANTO CATALYTIC OXIDATION (ADD-ON)	VANADIUM PENTOXIDE CATALYST (PERIODIC REPLACEMENT)	RECOVERY OF DILUTE H_2SO_4	45 - 50 (1000 MW. NEW)	2.1 - 2.5	1.8 - 2.2	80-90%.	COSTS DEPENDENT ON SAME FACTORS AS FOR WET LIMESTONE BOSTON ELECTRIC UNIT TO START-UP IN MARCH 1972 H_2SO_4 ASSUMED MARKETED AT 9 $/ton (conc. basis)

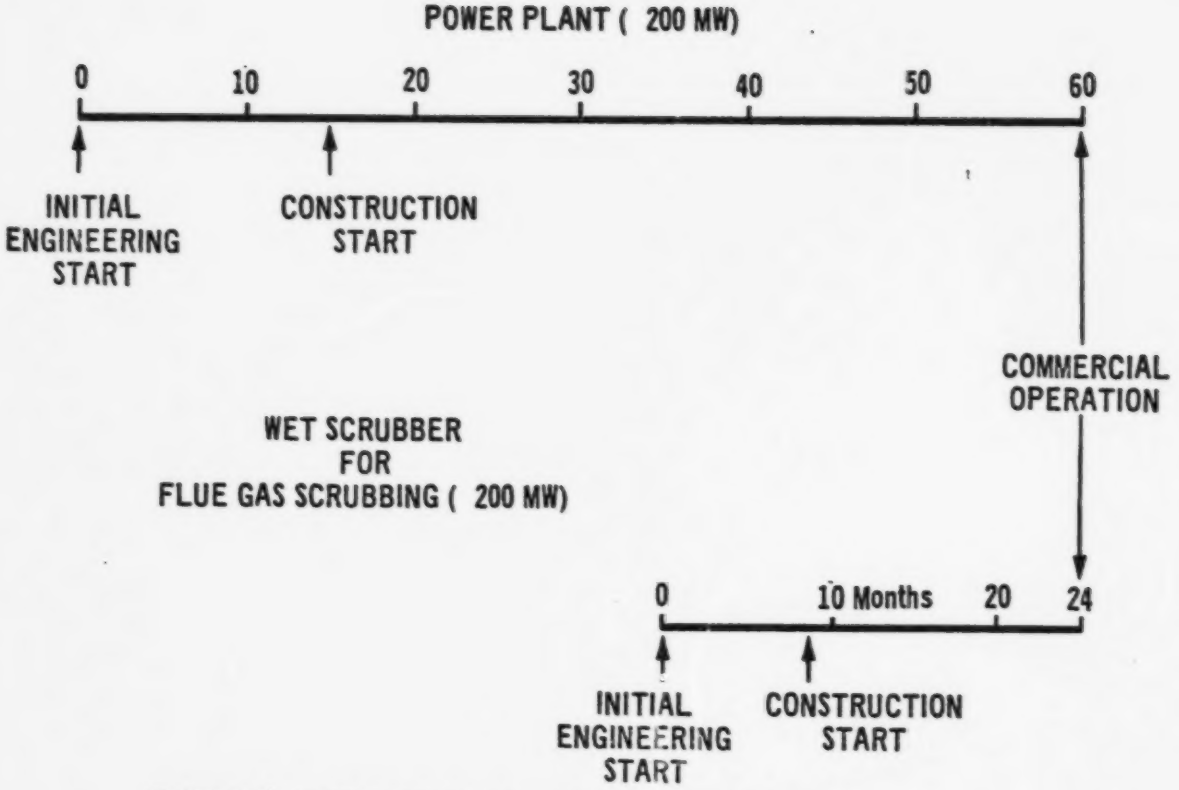
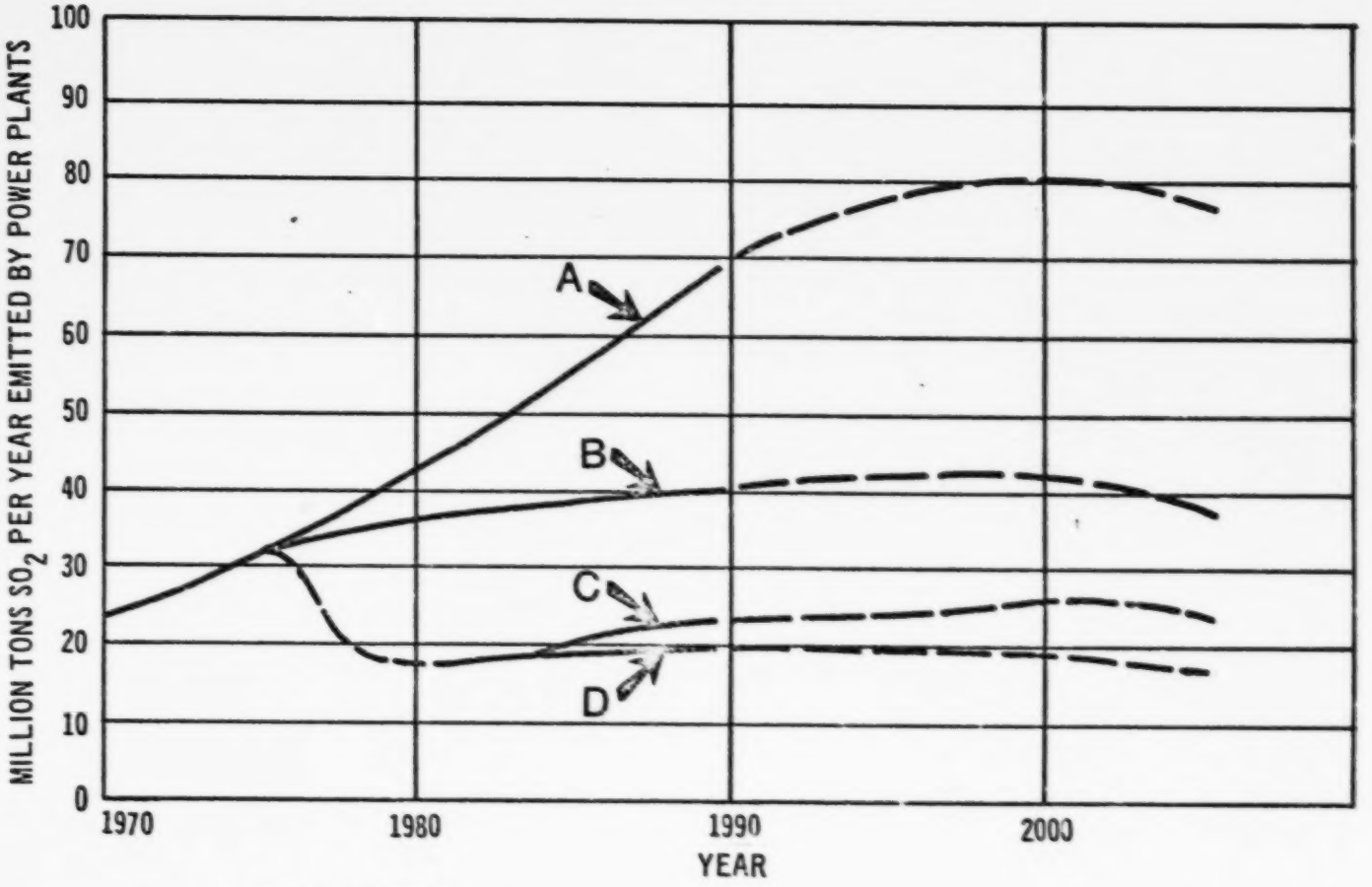


FIGURE 1. DESIGN AND CONSTRUCTION TIME CHART



A - NO CONTROL
B - 0.6 lb. S/10^6 BTU NEW PLANTS; NO CONTROL EXISTING PLANTS
C - 0.6 lb. S/10^6 BTU NEW PLANTS: AFTER 1975 1 lb. S/10^6 BTU EXISTING PLANTS
D - 0.6 lb. S/10^6 BTU NEW PLANTS PRIOR TO 1980; 0.3 lb S/10^6 BTU ALL NEW PLANTS AFTER 1980; AFTER 1975 1 lb. S/10^6 BTU EXISTING PLANTS
(NEW PLANTS - i.e., CONSTRUCTION STARTS AFTER NOV. 1, 1971)

FIGURE 2. EFFECTS OF SO_2 CONTROL STRATEGIES ON TOTAL POWER PLANT SO_2 EMISSIONS.

FIGURE 3.

ESTIMATED ANNUAL ELECTRIC UTILITY GENERATION BY PRIMARY ENERGY SOURCES

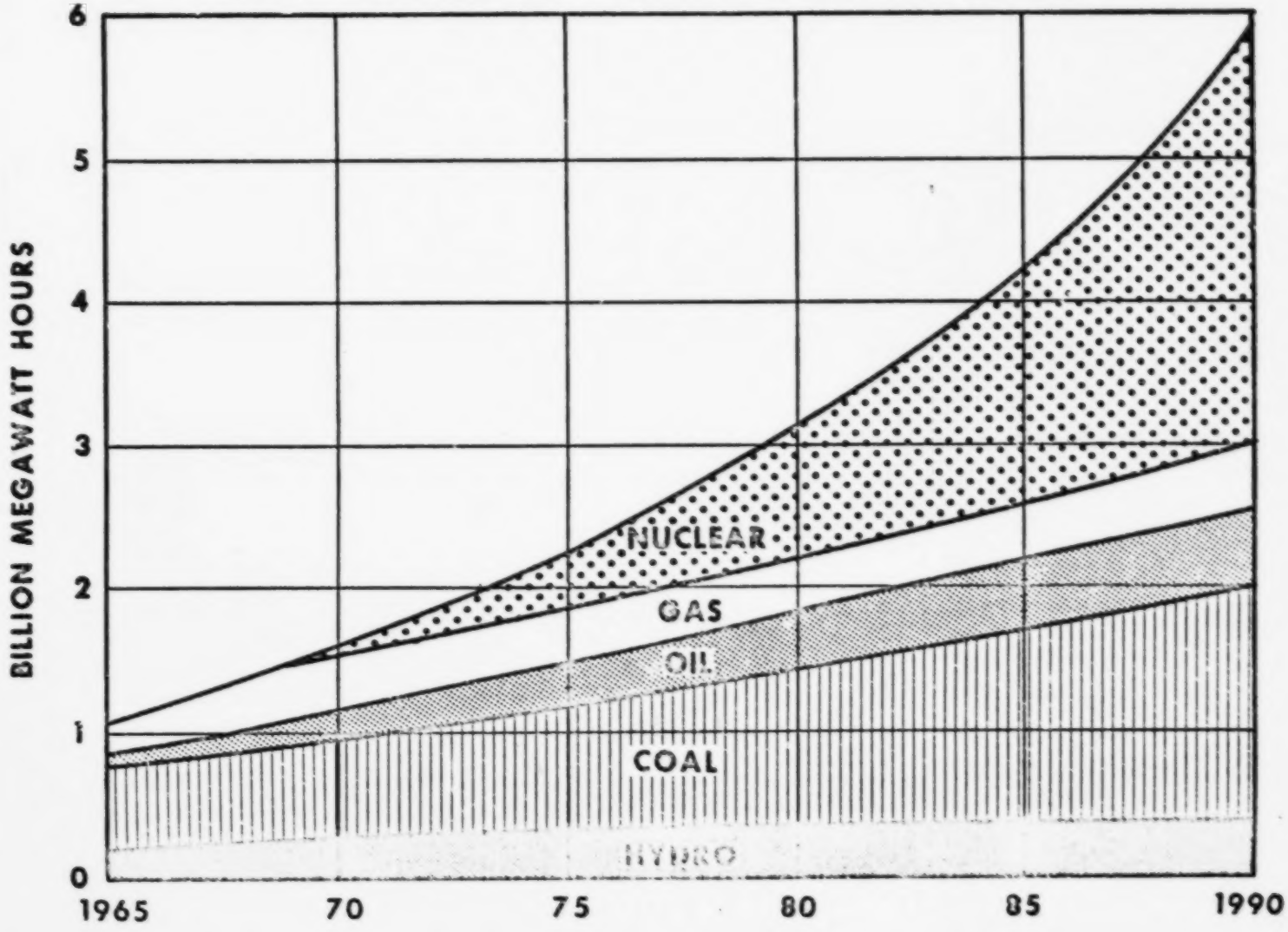
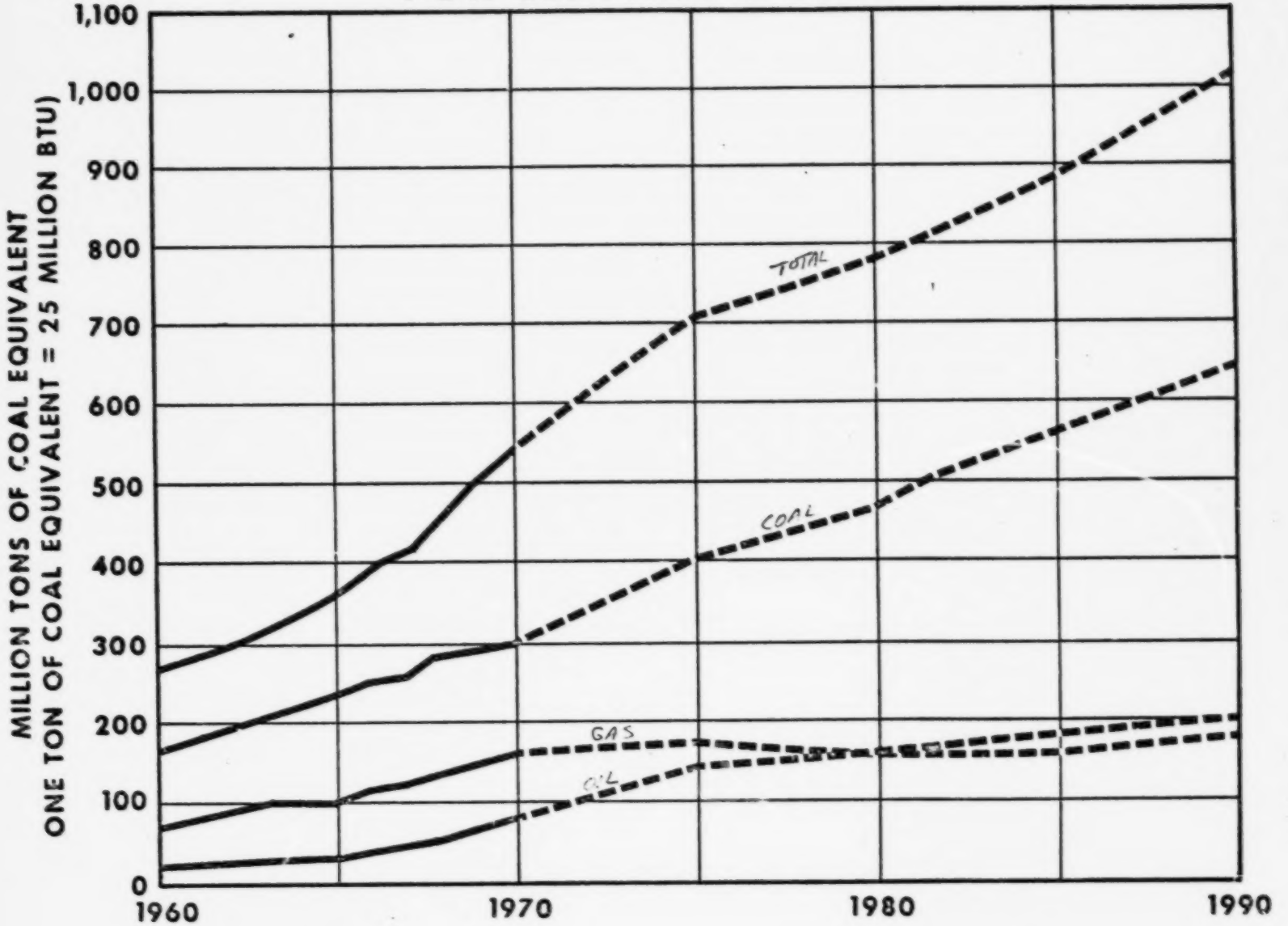


FIGURE 4.

ESTIMATED ANNUAL FOSSIL FUEL REQUIREMENTS FOR ELECTRIC UTILITY



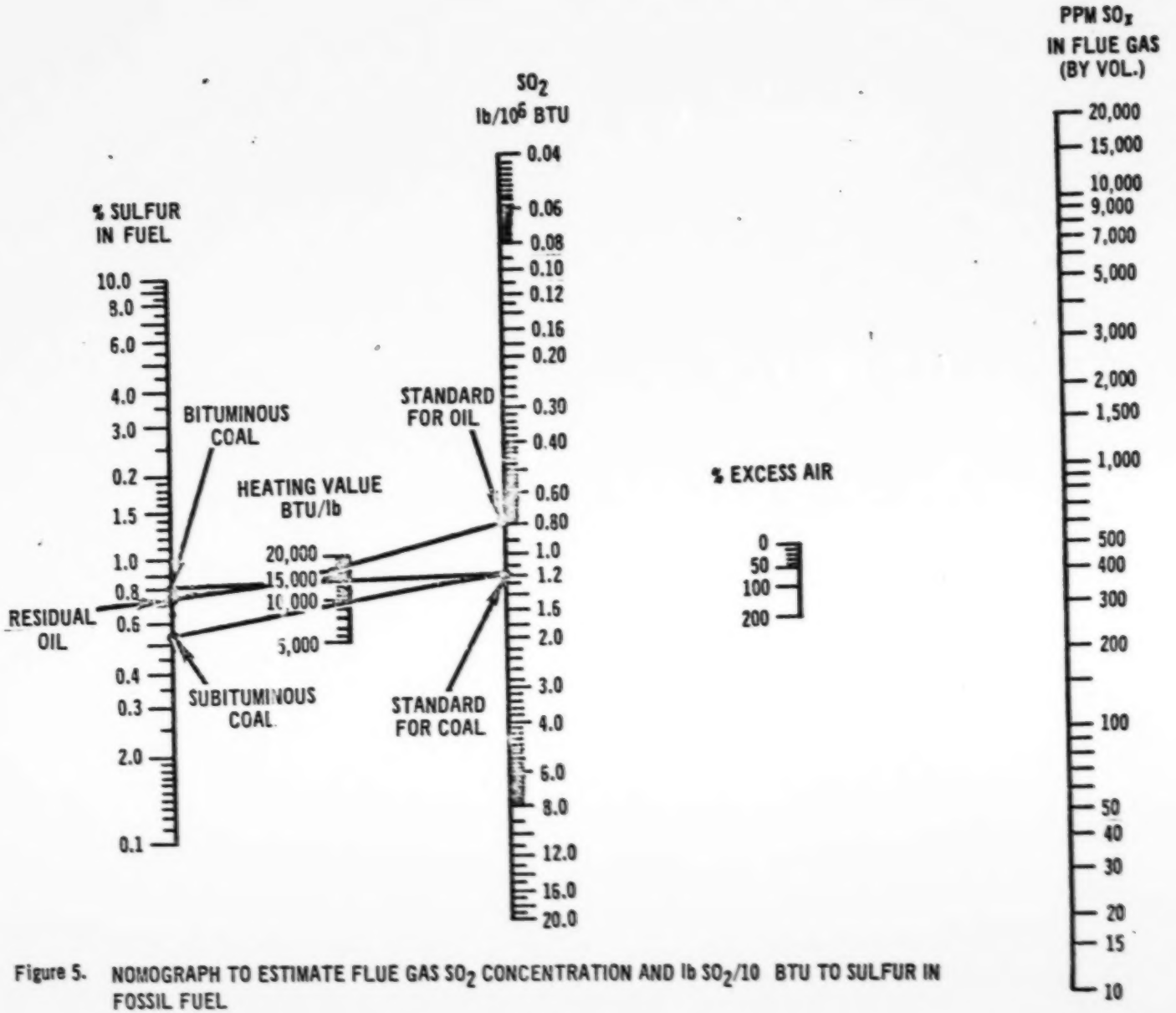


Figure 5. NOMOGRAPH TO ESTIMATE FLUE GAS SO_2 CONCENTRATION AND lb SO_2/10 BTU TO SULFUR IN FOSSIL FUEL

FIGURE 6.

DISTRIBUTION OF SULFUR CONTENT OF COAL BURNED BY ELECTRIC UTILITIES (1969)

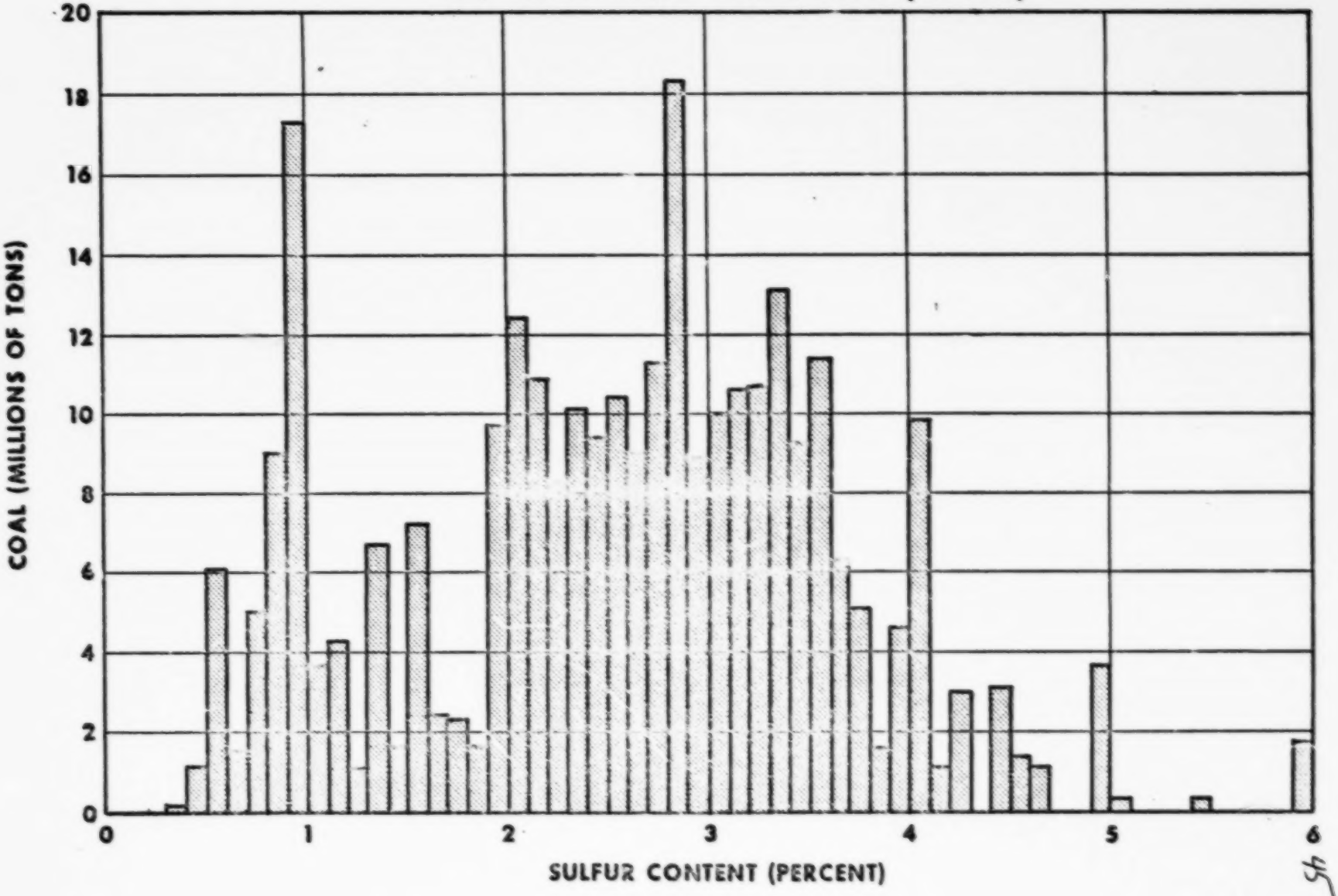
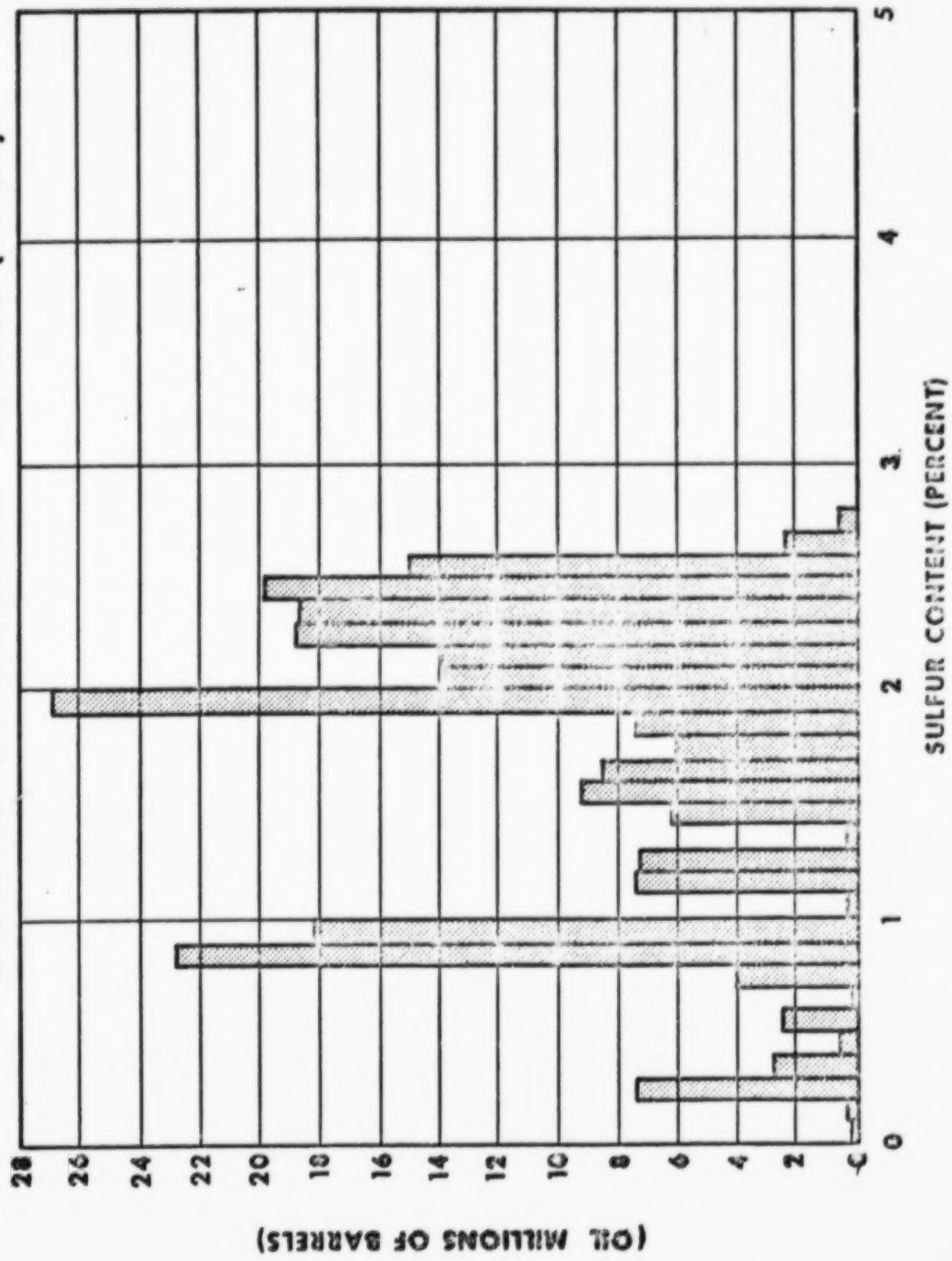
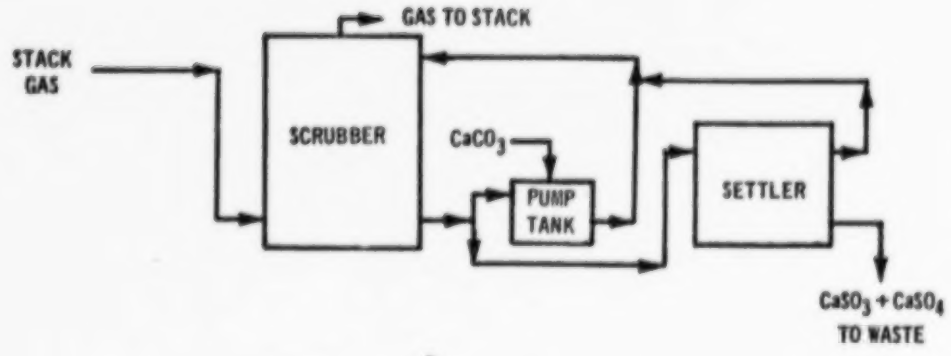


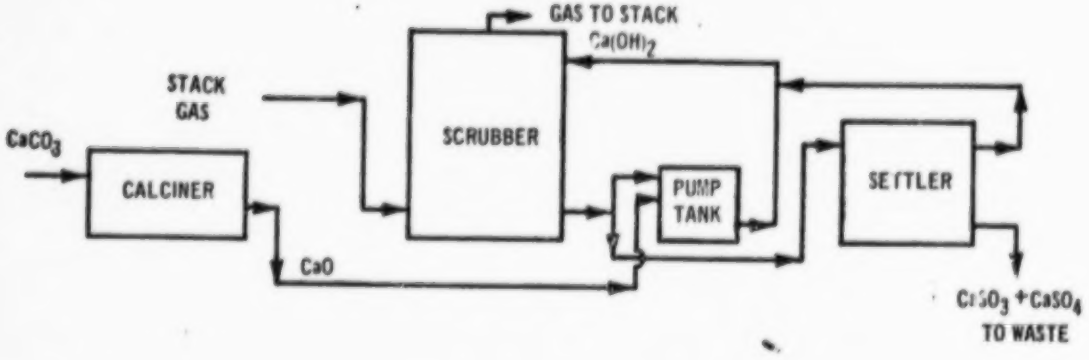
FIGURE 7.

DISTRIBUTION OF SULFUR CONTENT OF OIL BURNED BY ELECTRIC TILITIES (1969)

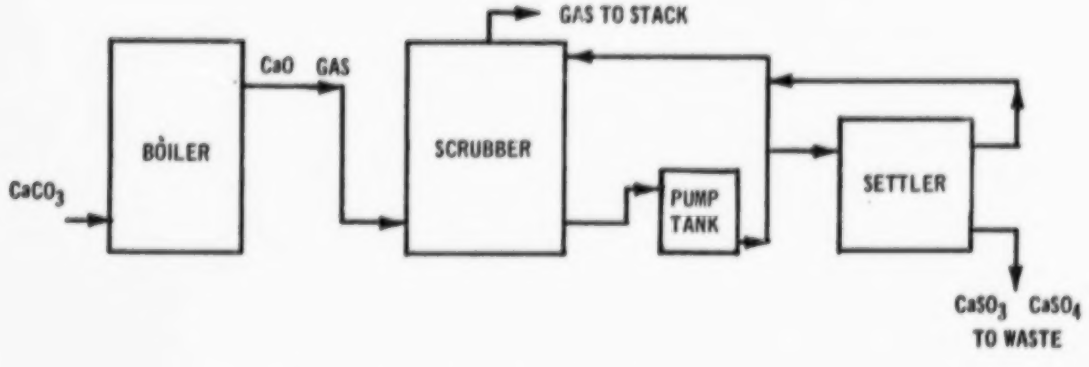




METHOD 1. SCRUBBER ADDITION OF LIMESTONE



METHOD 2. SCRUBBER ADDITION OF LIME



METHOD 3. BOILER INJECTION

FIGURE 8. MAJOR PROCESS VARIATIONS FOR USE OF LIME OR LIMESTONE FOR REMOVAL OF SO_2 FROM STACK GASES.

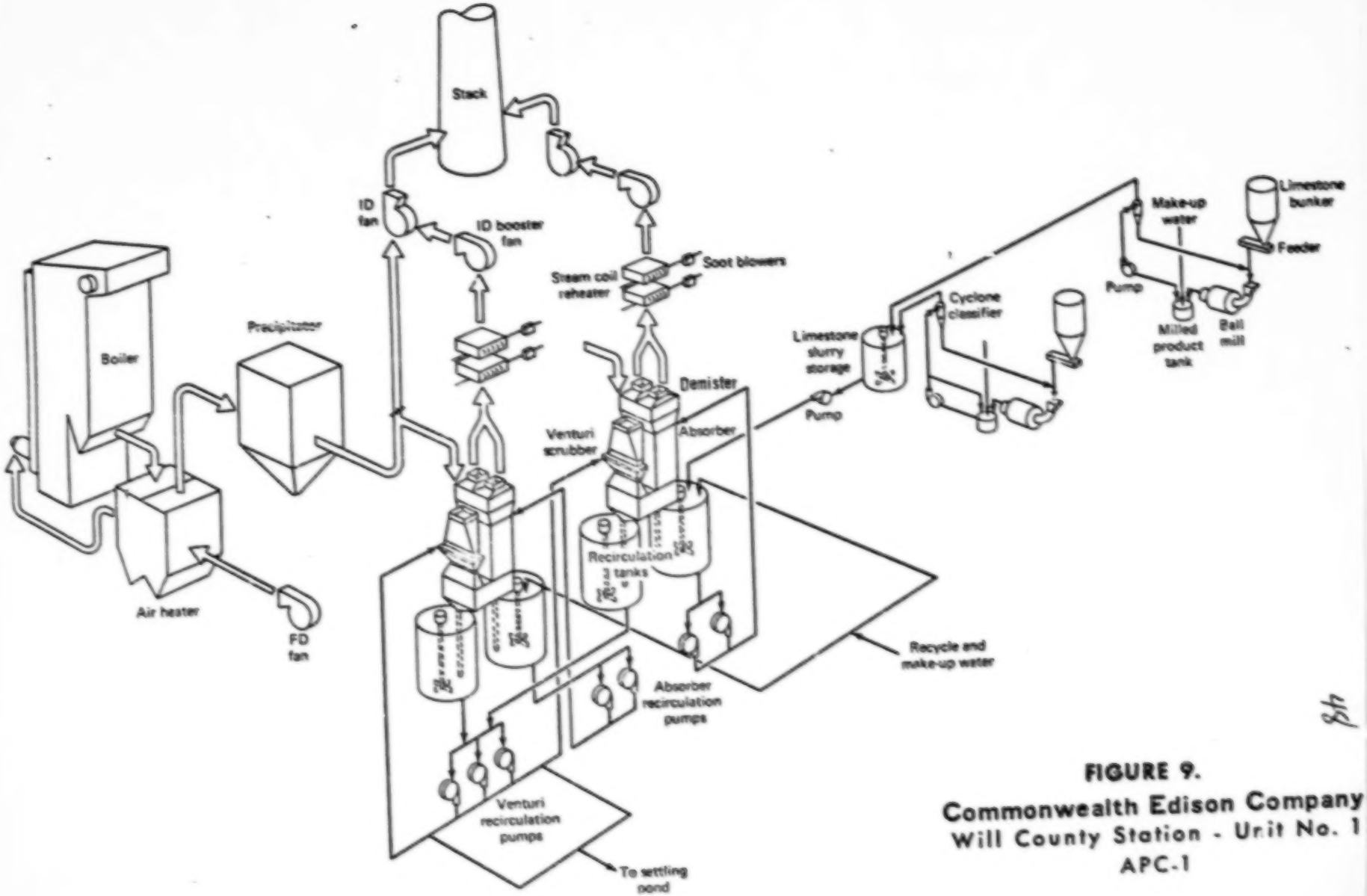


FIGURE 9.

Commonwealth Edison Company
Will County Station - Unit No. 1
APC-1

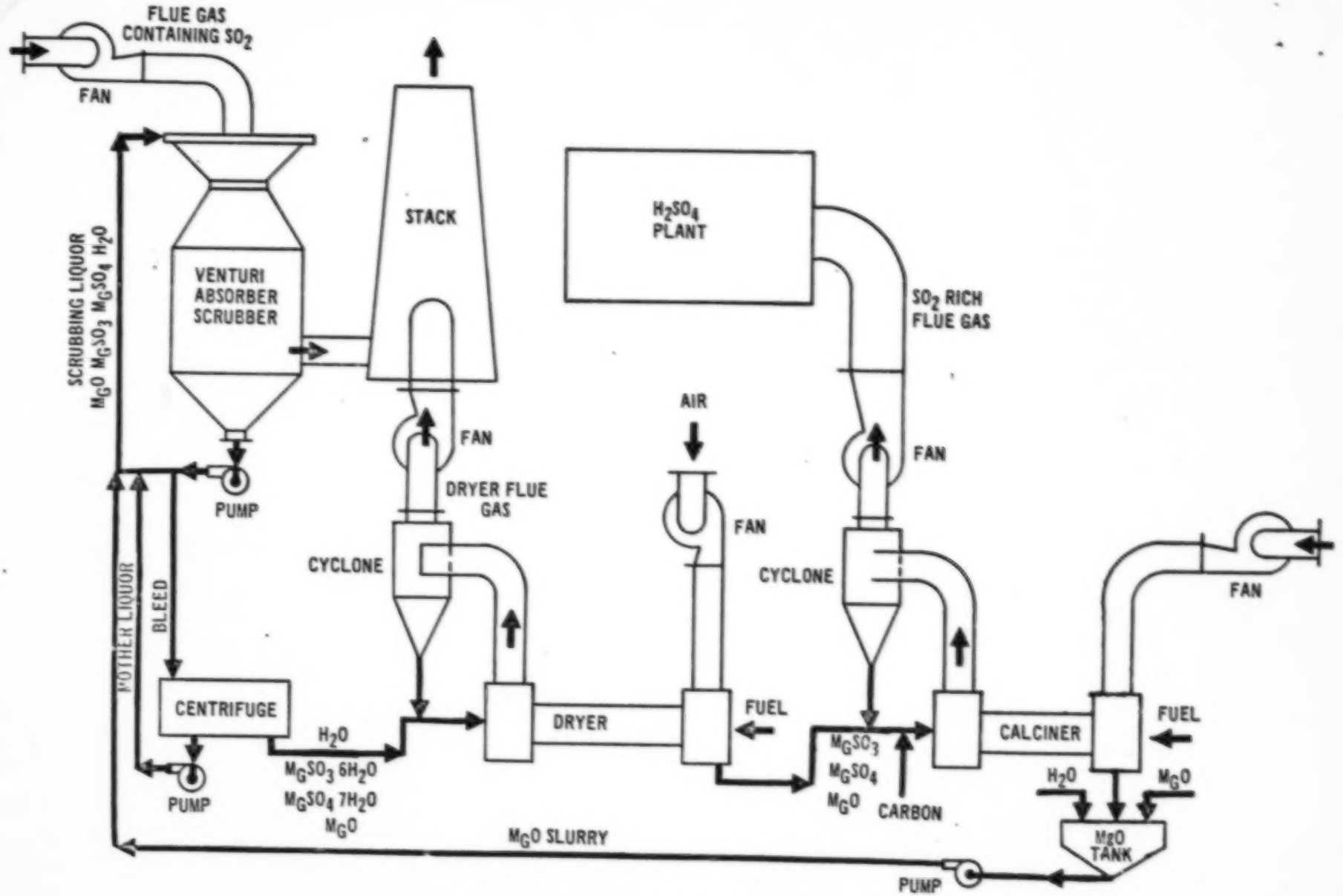


FIGURE 10. MgO SLURRY PROCESS - FOR FLUE GAS FREE OF PARTICULATE MATTER.

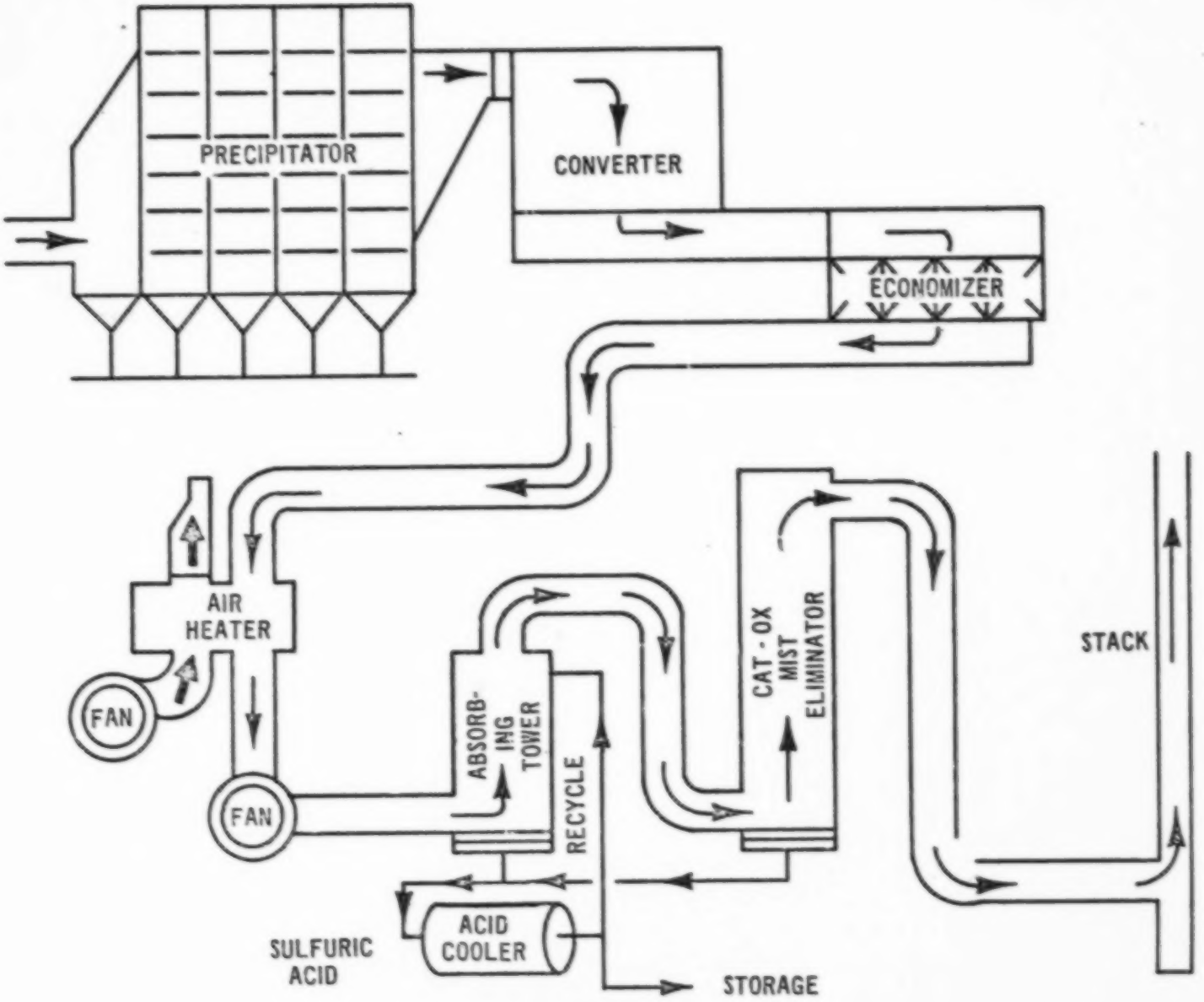


FIGURE 11. INTEGRATED CAT - OX PROCESS.

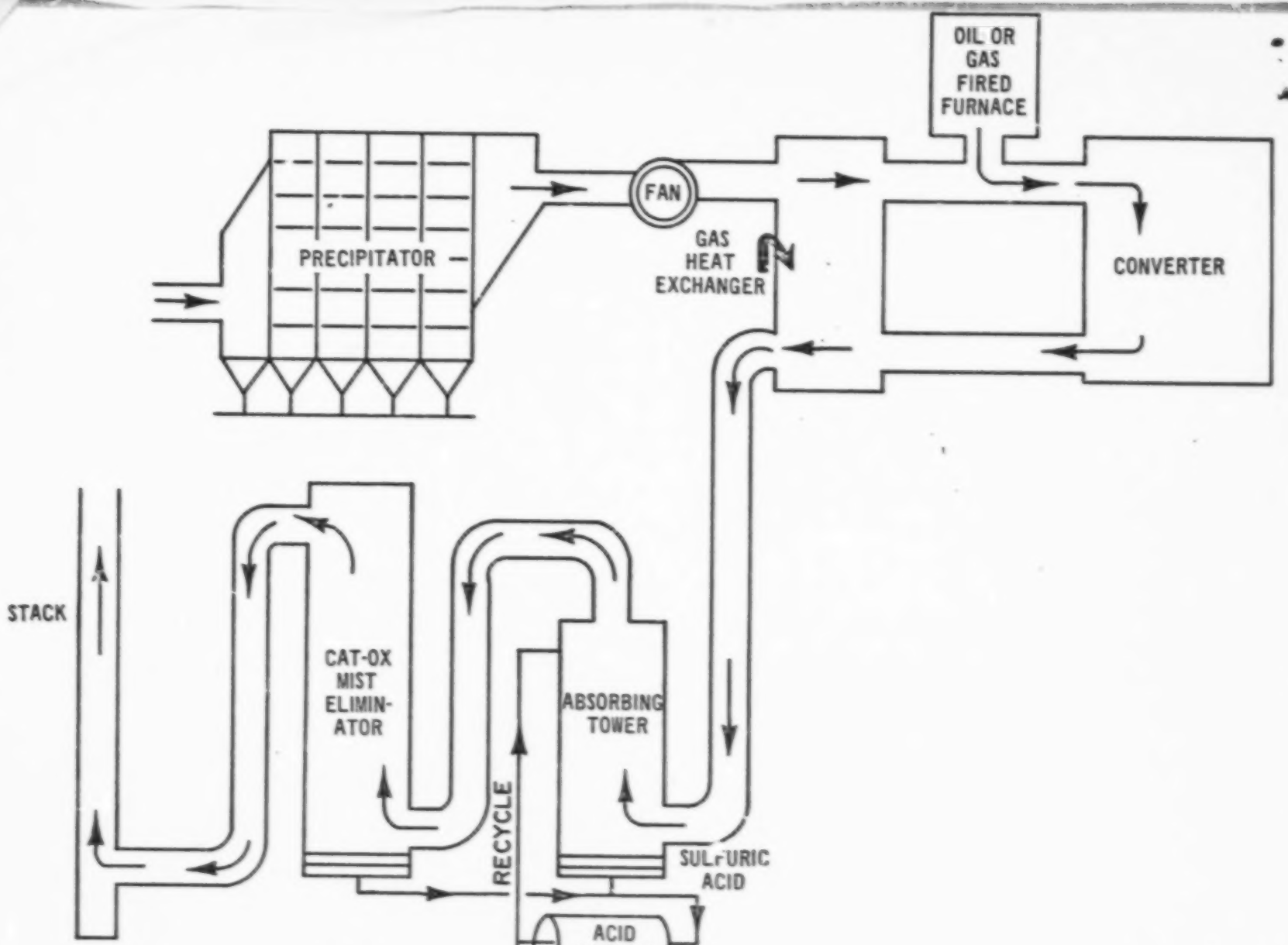


FIGURE 12. REHEAT CAT - OX PROCESS